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THE POTENTIAL IMPACT OF ENVIRONMENTAL EXTERNALITIES ON NEW RESOURCE SELECTION AND ELECTRIC RATES

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Executive Summary

The Massachusetts Department of Public Utilities (MDPU) recently required that the evaluation of all new resource acquisitions by electric utilities include the cost of certain environmental externalities. The externalities values adopted by the MDPU were those proposed by the Massachusetts Division of Energy Resources (MDOER) and developed by the Tellus Institute. The externalities addressed by the MDPU are a more comprehensive list of pollutant emissions than is covered in the recently enacted federal Clean Air Act Amendments.

In practice, the decision of the MDPU means that each Massachusetts utility, as it selects among resources, must consider the differences in emissions of pollutants from each option, as well as such conventional criteria as price, location, and unit availability. It is evident that the MDPU's decision will, over the long run, result in significant improvements in air quality.

It is also evident that as emissions considerations are added to the criteria for resource selection, there is likely to be some impact on rates. This report examines the potential rate impacts on the assumption that the MDPU's externalities values are adopted throughout the New England Power Pool (NEPOOL) region.

The focus of this report is the development of idealized scenarios which are designed to yield an estimate of the **maximum** impact rather than the most likely impact. The analyses indicate that the **maximum** rate impact -- that is, the increases above what one would anticipate if externalities were not a consideration -- is about 5

percent by the year 2006, the last year of the study period. Impacts in earlier years will be significantly lower.

I. Introduction

The Massachusetts Department of Public Utilities (MDPU) recently required that the evaluation of all new resource acquisitions by electric utilities include the cost of certain environmental externalities.[1] The externalities values adopted by the MDPU were those proposed by the Massachusetts Division of Energy Resources (MDOER) and developed by the Tellus Institute; the values are shown in Table 6, in the Appendix.[2,3]

The approach taken by the MDPU was to **monetize** the costs or value of these externalities (air emissions); that is, a dollar value was assigned to each.[4] Thus, once

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[1] Order, D.P.U. 89-239, August 31, 1990, pages 51-85. The environmental externality values which must be included at this time are for air emissions: nitrogen oxides, sulfur oxides, volatile organic compounds, total suspended particulates, carbon monoxide, carbon dioxide, methane, nitrous oxide. Utilities are also required to consider all impacts from project operation -- air, water, solid waste, spent fuel, resource use -- in the project evaluation process. Non-environmental externalities, if their levels and costs can be reasonably estimated, may be included on a case-by-case basis.

[2] The MDPU's values are found in Table 1, page 85, of its 8/31/90 Order in D.P.U. 89-239. The MDPU's values are in 1989 dollars. The values in Table 2 in the Appendix to this report are escalated to 1990 dollars.

[3] In Nevada, the Public Service Commission has promulgated a proposed rule which, for non-attainment areas, utilizes the same externalities values as does Massachusetts. Resource Plan Rulemaking, Docket No. 89-752, November 21, 1990.

[4] Note that the MDPU's approach to the monetization of externalities was to use the marginal cost of control as a proxy for the marginal benefits to be obtained from controlling pollution. A comprehensive description of the rationale for adopting this approach may be found in D.P.U. 89-239 (pages 60-72).

This report uses the terms externalities "costs" and "values" interchangeably. No different meaning is intended in the selection of one or the other. In each instance the choice was made solely for expositional reasons.

the anticipated emissions of a particular pollutant from a proposed facility are estimated, the emissions can be valued. When the externalities costs of electricity production are added to the direct costs (such as fuel), the full, or societal, costs are obtained.

It is evident that the inclusion of monetized externalities will affect the ranking of proposed projects. Indeed, some projects with relatively low direct costs, which would rank high on that criterion, now may be ranked lower. There is no doubt that the impact of the inclusion (or internalization) of externalities costs will be more significant for the development of some types of projects than for others. Thus, one should anticipate that there will be some change in the types and costs of resources acquired by utilities.[5]

One should also anticipate, therefore, that the shift in protocols could increase the costs (rates and bills) to utility customers.[6] The purpose of this report is to estimate the range of plausible ratepayer impacts by using some hypothetical scenarios. The focus of these scenarios is upon the inclusion of externalities values in only the selection of future, or incremental, resources. The impact of changes in the operation of the existing system is not estimated directly. In other words, the principal

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[5] Note that the MDPU has required the monetization of air emissions only at this time. The utilities are required to monetize all environmental externalities to the greatest extent possible. See, e.g., D.P.U. 89-239, page 73.

[6] The assumption here is that the cost to ratepayers may be up to, but no more than, the societal cost (or price) of a selected resource. In other words, in some circumstances, utility customers might pay more than the direct costs of a resource.

focus of the report is an examination of long-range planning, not short-run operating (or dispatching), decisions. However, because of the recent passage of the federal Clean Air Act Amendments, their likely impact on system operations is discussed briefly.

The study assumes that the MDPU's externalities values are adopted on a region-wide (or NEPOOL-wide) basis.[7] The rate impact estimates should be considered as a first look at the issue. More work is necessary to refine the scenarios and the associated costs. At the present time it appears that the rate impacts are not likely to be more than 3 percent through the year 2000 (on a cumulative basis) or 5 percent over the study period, 1991-2006. In fact, because the scenarios are designed to examine the potential maximum impacts, the actual impact would likely be significantly less. One must also consider, of course, the benefits obtained -- reduced air emissions -- and compare them to any incremental costs to ratepayers.

The DOER views this report as one which begins to sharpen the dialogue on these important issues. The report is not intended to be exhaustive or definitive. Comments and criticisms are welcome, as are suggestions for expansion and refinement of the study.

The details of the scenarios, including all assumptions, are described in Section II; additional information is provided in several tables.[8] Section III is a brief

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[7] NEPOOL is the acronym for the New England Power Pool.

[8] Tables 1-4 are contained within the text of this report. The rest of the Tables, 5 through 15, are found in the attached Appendix.

discussion of the possible implications of the federal Clean Air Act Amendments on system operations. Section IV is a short conclusion.

II. Rate Impact Scenarios

A. Introduction

The monetization of an externality means, simply, that a dollar value is assigned to that externality. Thus, for example, if the cost of a pound of pollutant X is $0.01, one may then calculate its costs on a cents/kilowatt-hour basis (with the appropriate additional information, such as the amount of the pollutant released when the fuel is combusted (lbs/MMBTU) and the facility's heat rate (BTU/KWH)).

It should be clear that the externalities costs vary directly with the amount of emissions and the value placed on them. When the direct costs per kilowatt-hour are added to the externalities costs per kilowatt-hour, the societal cost of electricity generation is obtained.

In the absence of the consideration of externalities, two equivalent generating facilities with the same direct costs (but different emissions) would rank equally. With the inclusion of externalities, the ranking could change. All else equal, the facility with the lowest societal cost (direct costs plus externalities costs) would be selected.[9] The

[9] We recognize that one should consider numerous other factors in the selection and acquisition of resources. Of particular importance will be requirements for system diversity.

key question for this report is whether, to what extent, and in what circumstances, changing the selection criterion may lead to higher rates for utility customers.

One should anticipate that in both the near-term and the long-term, reliance on the societal test will spur the search for cleaner modes of electricity generation. In the near-term, this might result in, for example, cogeneration applications that were not competitive prior to the inclusion of externalities. In the long-term, it is likely to spur the development of significant technological change.

B. General Description of the Scenarios

The approach taken to the estimation of potential rate impacts was to examine three simplified supply expansion plans for NEPOOL and to explore, by comparing them to one another, what rate effects might transpire as one moved to a societal cost criterion for resource acquisition. Wherever possible, these analyses are based upon NEPOOL data.[10] Because of the myriad possible expansion plans or scenarios, the three selected cases were chosen for illustrative purposes.

In each illustrative case, the assumed capacity increments are exactly 500 MW/year. In the first, the expansion is entirely **coal-fired**; in the second, it is gas

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[10] The decision to use NEPOOL data was made for practical reasons. We have not undertaken an independent review of their assumptions. However, even if, for example, NEPOOL's capital cost estimates were 10 or 20 percent too low -- and correspondingly higher values were used in this report -- the results would not be materially affected.

combined cycle.[11] The third assumes a **completely clean** (zero emissions costs) set of plant additions. The types of resources (power plants and demand-side management (DSM) investments) which might satisfy this criterion obviously include those which have no emissions. In addition, for example, the criterion could be met by a hypothetical cogeneration plant for which the emissions costs associated with electricity generation were exactly offset by lower emissions costs from the existing steam generators.

Each of the expansion plans is an idealized, essentially non-diverse, vision of NEPOOL's future.[12] None will transpire precisely, although NEPOOL forecasts significantly greater reliance on gas than other resources. Both the completely clean, (zero emissions costs) scenario and the all coal scenarios are extremely unlikely at this time, either with or without the inclusion of environmental externalities. We utilized these scenarios, however, so as to obtain plausible maximum rate and emissions

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[11] Plant specifics are described in the attached tables. Note that the plant sizes assumed for costing (400 MW for coal and 200 MW for the gas combined cycle) do not precisely match the assumed 500 MW annual capacity increments. The 500 MW size for capacity additions is a "smoothed" value which allows for straightforward comparisons of scenarios. The use of more detailed expansion scenarios would not affect our general conclusions.

[12] It is likely that the region will continue to see the addition of other types of resources such as wood and hydro. Their omission from these scenarios was based upon a need to limit the analytical requirements and a desire to provide a readily comprehensible illustration of impacts.

impacts.[13] The rate impacts -- and the corresponding changes in air emissions -- will obviously depend upon what cases or scenarios are being compared.

The impact on customer rates will also depend somewhat upon the manner in which the costs for facility development, construction and operation are recovered from ratepayers. The study examines both traditional ratemaking (utility owned and operated facilities) and contract purchases.[14]

The distinctions between the two are not precise. In Massachusetts, for instance, power from future utility-owned resources will be provided under contract, in much the same manner as is power from generators other than the utility itself, should the utility's resource be selected in its own resource solicitation.[15] This is not the rule in the other New England States. The assumption here is that both traditional, utility-owned and contract facilities will become part of the region's generation mix.

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[13] It is important to stress that the scenarios are not intended as base case projections of the manner in which the region's needs may be met. The study's scenarios are not the most probable and are designed to yield estimates of the maximum, rather than the most likely, rate impacts.

[14] Contract power may be purchased by a utility from a Qualifying Facility (QF), an Independent Power Producer (IPP), or from another utility. Since payments for power purchased under contract depend upon the specific contract terms, a simplifying assumption is necessary for the purposes at hand. For all contract purchases, it was assumed that the utility would pay (and recover from ratepayers) for capital costs over a 20 year period on a nominal levelized basis; fuel would be treated as a pass-through cost.

[15] D.P.U. 89-239, pages 6-7. Strictly speaking, Massachusetts utilities will submit bids in their own resource solicitations. As a practical matter, the bids will likely be submitted by subsidiaries. In any event, should the utility (or subsidiary) be a successful bidder, it will sell its power under contract. There is no longer traditional (ratebase) ratemaking for incremental resources.

C. Conclusions

This section describes the comparisons between the various scenarios.

Gas versus Coal

The projected direct costs (capital, fuel, fixed and variable O & M) of the **all-gas** and **all-coal** expansion scenarios are shown below in Table 1. While all projected costs have some variability about them, it is our judgment that the future of gas prices is the key variable that determines which scenario is more or less costly.

Table 1

Direct Costs of New Generation
(includes capital, fuel and O&M)
(millions of $)

Scenario	1995	2000	2005
All Coal	1,859	4,273	7,450
All Gas	976	2,416	4,579
Zero Emissions	1,269	3,176	6,059

*The above figures represent the annual costs of owning and operating all of the new capacity added between 1991 and the year indicated.

Consider the year 2000 as an example. With traditional ratemaking, our computations show an average rate of 17.6 cents/kilowatt-hour for the all coal scenario

and 16.3 cents/kilowatt-hour for the all gas scenario (Table 2).[16] Indeed, in all years considered (1991 to 2006), gas is less expensive. Whether or not that obtains for each year over the 35 year life assumed for capital cost recovery, and for life-cycle costs, will depend upon the relative escalation of gas and coal costs.[17]

Table 2

Average Electric Rates
(cents per kwh)

Scenario	1995	2000	2005
All Coal	12.8	17.6	23.6
All Gas	12.0	16.3	21.7
Zero Emissions	12.3	16.8	22.7

*These are the estimated average electric rates to consumers--including all utility costs and all electric sales--not just the new resources.

[16] The figures in Table 1 were derived on the assumption that half of the capacity which is added is traditional utility plant and half is under contract. Because of the manner in which costs are recovered, there is some difference between the two. The general results will not change significantly with changes in the relative percentages unless there are dramatically different costs for power between the two. We have not assumed such difference, but, rather, only differences in the pattern of payments. A discussion later in the text provides more detail concerning our assumptions.

[17] A comprehensive planning exercise would examine gas prices in some detail. In particular, one would examine the relationship between gas price escalation and the extent to which gas is relied upon for both electric generation and other uses. For the purposes of this study, such refinements have not been made.

If the costs of externalities are included, gas will be the clear choice.[18] The air emissions benefits of the gas versus coal scenarios may be seen in Table 3. For example, there are emitted 28 thousand less tons of NO_x, 63 thousand less tons of SO_2 and 15 million less tons of CO_2 in the gas scenario in the year 2000. Cumulatively, through the year 2000, the reductions are 384 thousand tons, 858 thousand tons, and 203 million tons for NO_x, SOx, and CO_2, respectively (derived from Tables 10 and 13 in the Appendix). Table 4 shows the emissions costs from new generation, using the Department's values for all emissions.

Table 3

Year 2000 Air Emissions from New Generation
(tons)

	All Coal Scenario	All Gas Scenario	Difference
CO_2	31,572,000	16,636,000	-14,936,000
CH_4	237	259	+22
CO	3,789	2,864	-925
N_2O	5,130	1,064	-4,066
NO_x	33,151	4,909	-28,242
SO_x	63,144	82	-63,062
TSP	4,736	136	-4,600
VOCs	631	4,500	+3,869

[18] It bears repeating that these are idealized scenarios. We have not considered such important matters as diversity which are likely to play a sizeable role in the decisions concerning the region's resource mix.

Table 4

Emissions Costs from New Generation
(millions of $)

Scenario	1995	2000	2005
All Coal	711	1,829	3,531
All Gas	290	747	1,442
Zero Emissions	0	0	0

A key question, of course, is whether or not electricity costs will be greater than otherwise if externalities are included in the resource acquisition process. The analyses here (which rely heavily on NEPOOL/NEPLAN assumptions), strongly indicate the possibility of a win-win situation. That is, the gas expansion case is less environmentally damaging than the coal scenario and may be less expensive as well. The result here may be generalized; rate impacts will be minimal where, as in this case, the lower cost option is also less costly to the environment.

Given the projections for power costs in the region, it is reasonable to assume that gas plants will be the marginal new resource for the foreseeable future. In the absence of staggering gas costs, the societal costs of conventional coal facilities will exceed that for gas, and gas will be the fuel of choice. If one assumes that utilities will not pay more than their own costs for comparable facilities, gas-fired power

provided under contract will not be more expensive to ratepayers, even if environmental externalities are considered.[19,20]

However, if the inclusion of externalities results in proposals to utilities for facilities which are cleaner than the marginal gas plant -- such as high quality cogeneration projects -- the costs to ratepayers might rise slightly. That is, the lower emissions costs might allow the developer to receive a higher price than he or she would have otherwise received. In such instances, the rate increment would of course be offset by reduced air emissions. This issue is explored further below, where the zero emissions costs facilities are compared to the gas plants.

The general conclusion -- concerning the comparison between gas and coal -- is that with gas on the margin, the monetization of air emissions by the entire NEPOOL region is not likely to affect rates in the region in a significant way, as long as one is comparing gas with comparably priced facilities having greater emissions. We turn now to a comparison of the gas expansion plan with the completely clean scenario.

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[19] In Massachusetts, utilities will no longer calculate their avoided costs as in the past. Each utility will bid to supply power in its own service territory; and returns to equity are not limited to regulated levels. Thus, an assumption that rates will be no higher than calculated avoided costs, is, in effect, an assumption that competition will limit rates to that level.

[20] To be precise, the assumption means that the facilities will be of equal cost to ratepayers over comparable periods of time (on a net present worth basis). However, rates in any given year will differ between the two because of the differences in the manner in which capital costs are recovered.

Gas versus Completely Clean Resources

This comparative analysis assumes that gas combined cycle facilities are on the margin. It also assumes that a utility will pay no more for power (or for saving power) than the societal cost of that facility: that is, the sum of its direct costs and associated externalities costs. Thus, were a facility or DSM resource to have zero emissions, the ratepayers might pay as much for that resource as the societal costs for the gas facility rather than its direct costs.[21] The difference between the two -- the emissions costs of the gas combined cycle facility -- is the maximum revenue (and customer rate) impact from the inclusion of externalities in the resource acquisition process.[22]

Consider the following hypothetical numbers for illustrative purposes. Suppose that the direct costs of power from a fossil facility on the margin were 10 cents/kilowatt-hour levelized and that its associated emissions costs were 2 cents/kilowatt-

[21] As noted earlier, the assumption in this report is that ratepayers might pay up to the avoided societal costs for a resource. If, instead, the direct cost of the avoided resource is the maximum price to be paid for incremental resources, the selected mix would differ, as would the revenue and rate impacts. And if this criterion resulted in the exclusion of resources with prices between the direct and societal cost of the avoided resource, the resultant resource mix would not be optimal from the societal perspective.

[22] If the clean facility has direct costs which are lower than the gas combined cycle direct costs, it could sell power for less than the gas direct costs, whether or not externalities are considered. Thus, after externalities are included, it might appear that the increase to ratepayers for clean power could be greater than value of the emissions associated with gas generation. However, since the clean facility could have sold its power for less than the gas direct costs prior to the inclusion of externalities costs, it is reasonable to conclude that the maximum increase associated with their inclusion is their cost.

hour levelized. A facility with zero emissions costs could thus sell power competitively at up to 12 cents/kilowatt-hour, which is the societal cost of power from the hypothetical marginal fossil plant (10 cents/kilowatt-hour plus 2 cents/kilowatt-hour).

If it sought to charge more for its power, it would not be a cost-effective resource for the utility. On the other hand, as a practical matter, if there is competition among clean resources for power purchase contracts from utilities, the transaction could take place at less than the societal cost of the marginal fossil plant.[23] In any event, the maximum increase in the cost of new power is 2 cents/kilowatt-hour, the cost of the emissions associated with the marginal plant's generation of electricity.[24]

Our estimates indicate the maximum impact on rates -- in the year 2000, for example -- will be no more than approximately 0.5 cents/kilowatt-hour , which is an increase of 3 percent (see Table 2). And over the study period, the years 1991 to 2006, the increase is no more than about 5 percent, prior to a consideration of the rate impacts of additional DSM.[25] The term "additional DSM" refers only to the DSM that would become cost-effective as a result of the inclusion of externalities in

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[23] In some instances, there is not only a value but also an additional cost to the cleaner facility. For example, a gas combined cycle plant with cogeneration (or with additional pollution controls) could required additional developer costs.

[24] As noted earlier, the idealized scenarios, including the completely clean scenario, are intended to estimate the maximum rate and emissions impacts rather than the most probable impacts. It is highly unlikely that any realistic expansion plan will consist entirely of projects with zero emissions costs.

[25] We stress once again that the estimates in this report are of the maximum impacts, not the most likely impacts, which will be lower.

the measure of societal cost-effectiveness. It is, in other words, the DSM which is over and above that which is cost-effective in the absence of any consideration of externalities.

The potential rate impact of the additional DSM investments is a complicating factor in this analysis. By reducing the kilowatt-hours over which a utility's fixed costs are spread, DSM investments may result in rate impacts which exceed those from comparable supply-side resources.[26] Whether or not the change in protocol -- from a direct cost to a societal cost criterion -- will result in significant rate impacts from DSM depends upon: (1) how much additional DSM becomes cost-effective with the change, (2) the kilowatt-hour savings from such investments, and (3) the dollar contribution made by the recipients of these DSM measures.

As a purely theoretical matter, if the completely clean scenario contains any additional DSM, the maximum increase in rates would be greater than if the scenario contained only supply facilities. The key question, then, is whether the estimate above -- a maximum increase of 5 percent -- should be increased. Our conclusion is that, as a practical matter, the 5 percent maximum remains an appropriate estimate.

The 5 percent maximum assumes that the cost to ratepayers of each of the completely clean supply projects is the total societal cost. In other words, it assumes

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[26] It is important to bear in mind the distinction between customer rates and customer bills. Rates are a measure of the costs per kilowatt-hour of usage; bills are the total payment required -- or number of kilowatt-hours multiplied by the rate. It is obviously possible for bills to be lowered as rates are increased, which will be the case if the number of kilowatt-hours consumed is reduced more than proportionally to the increase in the rate.

that competitive market forces are inadequate to drive some prices below that level -- that is, to a price somewhere between the direct and societal avoided cost. Were competition this weak, an increase in the estimate of the maximum impact would be clearly warranted. However, a plausible assumption is that the rate impact of the additional DSM is reasonably likely to be offset by the effects of competition on the price of the resources.

All in all, our assessment that 5 percent remains a reasonable estimate of the maximum rate impact is based in part upon judgments concerning market competition, the potential energy savings from the additional DSM, and the extent to which the recipients of this DSM are directly charged for it.

The issue of DSM rate impacts deserves substantially more scrutiny than was given to it here. Each of the factors alluded to in the previous paragraph and earlier will affect the extent to which the additional DSM results in rate increases. As more probable resource expansion plans are analyzed, a more thorough review of these issues would be warranted.

Nonetheless, despite the absence of a more detailed analysis, we are of the opinion -- for the reasons articulated above -- that 5 percent is a reasonable estimate of the maximum rate impact which would result from the inclusion of environmental externalities in the resource acquisition process.

Coal versus Completely Clean Resources

Depending upon the assumptions concerning gas price escalation principally, the direct costs of coal may be reasonably close to the direct costs for gas combined cycle, as discussed above. However, given the externalities values adopted by the MDPU, the societal costs -- direct plus externalities -- of conventional coal capacity are almost certain to be significantly higher than for gas. Thus, any comparison between coal and the zero emissions cost resources will be somewhat misleading.

Because the societal costs of coal generation exceed the gas generation societal costs, the zero emissions cost resources would generally not be displacing coal on the margin. Therefore, a comparison between the two will overstate both the potential rate impacts and emissions reductions. Because the comparison is not a useful one in the current circumstances, we do not pursue it here.

Summary

The preceding analyses were based upon highly simplified expansion plans for the NEPOOL region. We believe that the general conclusions will hold up as the analyses are refined. Unless there is a dramatic change in the relative direct costs of gas and coal facilities, the region-wide adoption of the MDPU's externalities values will result in rate impacts of no more than about 5 percent by the year 2006. Since 5 percent is an estimate of the maximum increase, it is likely that the actual rate impacts will be lower. The impacts will be the result of substituting for gas facilities

alternative facilities with lower externalities costs (zero in the extreme). Thus, the rate impacts will be offset by correspondingly lesser environmental impacts.[27]

The general conclusions should not be taken to imply that there will be no dislocations which result from the movement from a direct to a societal cost criterion for resource acquisition. For example, the developers of certain types of projects will find their comparative rankings altered, in some cases significantly. The consequences to them should not be trivialized. The examination here, however, is a look at the average impacts, from the ratepayers' perspective.

III. The Federal Clean Air Act Amendments

The Massachusetts rules concerning environmental externalities were adopted prior to the signing of the federal Clean Air Act Amendments on November 15, 1990. The federal act's amendments, as they relate to utility operations, concern SO_2 and NO_x only. The requirements concerning SO_2 are much more detailed. Described broadly, utilities will be granted a certain number of "allowances", each of which is an authorization to emit one ton of sulfur during a specified calendar year. If the amount of emissions exceeds the allowances for that year, the penalties provided for in the act must be paid.

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[27] If the region's diversity needs are met by facilities other than coal -- assuming gas is the primary generation expansion plant -- total emissions (and emissions costs) may either increase or decrease, depending upon what facilities are added.

The act anticipates that a market for allowances will develop. Allowances which are not used may be sold. Because a utility's allowances will have a sale value if not used, it will be necessary to optimize the utilization of the allowances -- that is, the emission of tons of SO_2.[28]

In our judgment, optimization of the SO_2 allowances will likely affect short-term operational decisions within NEPOOL.[29] In practice, NEPOOL members will have to reach some agreement on how to deal with the issue. One would anticipate that, among other approaches, there will be some reconsideration of the protocols for the dispatch of the region's generation facilities. We do not speculate here on the precise manner in which the federal act will be complied with.

The principal focus of this report is on the rate and emissions impacts of increments to the region's resources once environmental externalities have been included as a consideration. The brief discussion in this section is intended mainly to note that the federal statute will also have implications for facility emissions and customer rates. It is also our opinion that the provisions of the federal act will not preclude the region-wide adoption of environmental externality values for both SO_2 and NO_x, as well as other pollutants. Particular states, or the region as a whole,

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[28] More specifically, utilities and regulators will have to develop cost-effective methods for utilizing the allowances and avoiding penalties which are consistent with other important objectives of least-cost planning.

[29] Obviously, other activities will also be required. For example, it is likely that regulatory commissions will require that a utility undertake those investments in SO_2 reduction which are less costly than the anticipated market price for the allowances which would then be available for sale.

may -- for a variety of reasons -- desire more stringent requirements. Federal law and more stringent state requirements have co-existed in both the past and the present. Naturally, the adoption of externalities values must be done in a manner which is consistent with the requirements of federal law.[30]

As a final note, it should be kept in mind that, in addition to modifications of the regional dispatch order, there are many options available for reducing air emissions, and that the low cost options should, as a general rule, be undertaken first. Some options are exclusive with regard to a single generating unit (e.g., a coal unit would not simultaneously be retrofit with FGD, switched to natural gas and retired); for the total system, however, the options are not mutually exclusive. The best resource plan will consider the full range of available emissions reduction options.

IV. Conclusion

The idealized scenarios examined in this report were designed to yield plausible estimates of the maximum rate impact which would result from the region-wide adoption of the MDPU's environmental externalities values. The results indicate a maximum impact of no more than about 5 percent over the report's study period

[30] In fact, Massachusetts has its own SO_2 emissions regulations, specifying a statewide emissions cap and allowing emissions trading as a means of compliance. We believe that state-specific, regional, and national emissions regulations can be implemented simultaneously in a consistent manner. The interactions among the various efforts -- including the MDPU's emissions values -- deserves attention, but is not the subject of this report.

(1991-2006). Any increase in rates will be counterbalanced by a significant reduction in region-wide emissions.

As the text indicates at several points, there is room for much additional research and analysis. Particularly useful will be the development of impact studies which are derived from more probable resource expansion plans. As noted in the Introduction, this report is intended to sharpen the dialogue on these important issues; it is appropriately viewed as a first step rather than an exhaustive or definitive work.

APPENDIX

* Note: Tables 1-4 are contained within the text.

Table 5
Cost of Future Generation Scenarios

	1995 (million$)	2000 (million$)	2005 (million$)
All Coal Expansion (1)			
Cost of Utility-Owned Plants	$1,914	$4,273	$7,250
Cost of Contract Purchases	$1,804	$4,273	$7,650
Average Cost (4)	$1,859	$4,273	$7,450
Emissions Costs	$711	$1,829	$3,531
All Gas CC Expansion (2)			
Cost of Utility-Owned Plants	$994	$2,418	$4,521
Cost of Contract Purchases	$958	$2,413	$4,636
Average Cost (4)	$976	$2,416	$4,579
Emissions Costs	$290	$747	$1,442
All Clean Expansion (3)			
Cost of Utility-Owned Plants	$1,289	$3,191	$6,039
Cost of Contract Purchases	$1,248	$3,161	$6,079
Average Cost (4)	$1,269	$3,176	$6,059
Emissions Costs	$0	$0	$0

NOTES: (1) In this scenario, all new plants are assumed to be coal with FGD.

(2) All new plants built are Gas Combined Cycle units.

(3) Clean expansion assumes new plants have zero emissions. These plants could be hydro, wind, photovoltaic, or cogeneration plants where the incremental value of emissions from generation are exactly offset by the reduced emissions from the existing steam generation system. This is not intended as a general representation of cogeneration systems.
Real "clean" plants will probably not come online until about 1993 at earliest.

(4) Average cost is calculated by assuming that half of all new expansion is utility-owned and half is purchased under contract.

Table 6
Values for Air Emissions

	1990$/lb
CO_2	$0.012
CH_4	$0.116
CO	$0.452
N_2O	$2.082
NO_X	$3.418
SO_X	$0.789
TSP	$2.103
VOCs	$2.787

Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

Table 7
Emissions Coefficients for Selected Resources

lbs/MMBTU in

	Heat Rate (1) (BTU/KWH)	NOX	SOX	TSP	CO	VOCs	CO2	CH4	N20
Combined Cycle NG (2)	8302	0.036	0.001	0.001	0.021	0.033	122	0.002	0.008
Coal, w/FGD (3)	9611	0.210	0.400	0.030	0.024	0.004	200	0.002	0.033

lbs/MWhr out (4)

	NOX	SOX	TSP	CO	VOCs	CO2	CH4	N20
Combined Cycle NG	0.299	0.005	0.008	0.174	0.274	1013	0.016	0.065
Coal, w/FGD	2.018	3.844	0.288	0.231	0.038	1922	0.014	0.312

1990$/MWhr out (5)

	NOX	SOX	TSP	CO	VOCs	CO2	CH4	N20	TOTAL
Combined Cycle NG	$1.022	$0.004	$0.017	$0.079	$0.764	$11.717	$0.002	$0.135	$13.739
Coal, w/FGD	$6.899	$3.032	$0.606	$0.104	$0.107	$22.238	$0.002	$0.650	$33.639

NOTES: (1) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force , Dec 1989, p. 46, for plants running at 75% or 80% load.

(2) Gas Combined Cycle Emissions: All coefficients except for CO2 from Tellus Institute report, "Evaluation of Repowering the Manchester Street Station," A report to the Rhode Island Division of Public Utilities and Carriers, Rhode Island Division of Statewide Planning, and Rhode Island Governor's Office of Energy Assistance. [Source for Tellus report: emissions factors as reported by Narragansett Electric Company and New England Power Company, except for CH4 and N20 which are based on sources including US EPA (Policy Options for Stabilizing Global Climate: Draft Report to Congress, Feb. 1989) and California Energy Commission ("Staff Recommendations for Generic Power Plant Emissions Factors (Final Version)", August, 1989)]. CO2 coefficient calculated based on 75% Carbon content. Sulfur Content = .0007%; oxidation catalyst at 80% control for CO; SCR @ 80% control for NOX.

(3) Coal w/FGD Emissions: Coefficients for TSP, CO, VOCs, CH4 and N2O from same Tellus Institute report as in note (2). Coefficients for NOX, SOX, and CO2 calculated based on Eastern Bituminous Pittsburgh Seam coal as specified by EPRI (Technical Assessment Guide, Vol. 1, Electric Supply, 1989, Table 2-7). Composition of Eastern Bituminous by wt%: moisture=6.0, Carbon=71.30, Hydrogen=4.8, Nitrogen=1.4, Sulfur=2.6, Oxygen=4.8, Ash=9.1. Gross Heating Value(Btu/lb)=13,100. TSP and SOX controlled at 90%; NOX controlled at 65%.

(4) These values are calculated from the lbs/MMBTU in and the Heat Rate shown above.

(5) Calculated from values and coefficients of air emissions found in Tables 6 and above.

Table 8
Rate Impacts of Utility-Owned Coal Plant with Traditional Ratemaking

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4) (1990$/lb)

CO_2:	$0.012
CH_4:	$0.116
CO:	$0.452
N_2O:	$2.082
NOX:	$3.418
SOX:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions: (MW)

1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Coal Steam, 400 MW with FGD

Costs in	1990	dollars
Capital Cost (5) =	$2,082.42	/KW
Fixed O&M Cost (5) =	$35.06	/KW/year
Variable O&M Cost (5) =	$7.38	/MWH
Fuel Cost (6) =	$2.02	/MMBTU
Heat Rate (7) =	9611	BTU/KWH

Cost Escalation Rates (2) (for 1990)

Capital	6.1%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	5.7%
Air Emissions	5.2%

Air Emission Coefficients (8) (lbs/MMBTU In)

CO_2:	200
CH_4:	0.0015
CO:	0.0240
N_2O:	0.0325
NOX:	0.2100
SOX:	0.4000
TSP:	0.0300
VOCs:	0.0040

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9)

Year	
1	21.83%
2	21.30%
3	20.54%
4	19.83%
5	19.14%
6	18.49%
7	17.86%
8	17.26%
9	16.68%
10	16.10%
11	15.53%
12	14.95%
13	14.38%
14	13.80%
15	13.23%
16	12.66%
17	12.08%

NOTES: (1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.
(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force , Dec 1989, based on p. 16, see Table 5 for calculation of average..
(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.
(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.
(5) See note 2, p. 35.
(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39.
(7) See note 2, p. 46, heat rate for net plant heat rate at 80% load.
(8) See note 3 in Table 7.
(9) See note 2, p. 32.
(10) Plant type used to determine unit costs only.

Table 8 (continued)
Rate Impacts of Utility-Owned Coal Plant with Traditional Ratemaking

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate (cents/KWH)	Annual Rate Inc
1990	110000	$9,600	$0	$0	$0	$0	$0	$9,600	8.73	
1991	112233	$10,301	$241	$19	$26	$67	$353	$10,654	9.49	8.77%
1992	114511	$11,054	$491	$38	$53	$139	$721	$11,775	10.28	8.32%
1993	116836	$11,861	$748	$59	$82	$214	$1,103	$12,964	11.10	7.91%
1994	119208	$12,728	$1,013	$81	$112	$293	$1,500	$14,228	11.94	7.56%
1995	121628	$13,658	$1,287	$105	$145	$378	$1,914	$15,571	12.80	7.26%
1996	124097	$14,655	$1,570	$129	$179	$466	$2,345	$17,000	13.70	7.00%
1997	126616	$15,726	$1,864	$156	$215	$560	$2,795	$18,521	14.63	6.78%
1998	129186	$16,875	$2,169	$184	$254	$659	$3,265	$20,140	15.59	6.58%
1999	131809	$18,108	$2,486	$213	$295	$764	$3,758	$21,866	16.59	6.41%
2000	134484	$19,431	$2,816	$244	$338	$875	$4,273	$23,704	17.63	6.25%
2001	137214	$20,850	$3,160	$278	$384	$992	$4,813	$25,664	18.70	6.11%
2002	140000	$22,374	$3,519	$313	$432	$1,115	$5,379	$27,753	19.82	5.99%
2003	142842	$24,008	$3,894	$350	$484	$1,246	$5,973	$29,982	20.99	5.88%
2004	145741	$25,762	$4,285	$389	$538	$1,384	$6,596	$32,359	22.20	5.78%
2005	148700	$27,644	$4,693	$431	$596	$1,530	$7,250	$34,895	23.47	5.69%
2006	151719	$29,664	$5,121	$475	$657	$1,684	$7,937	$37,601	24.78	5.61%

NOTES: (1) All costs in nominal dollars for that year.

Table 9
Rate Impacts of Coal Plant Purchased Under Contract

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4)	(1990$/lb)
CO2:	$0.012
CH4:	$0.116
CO:	$0.452
N2O:	$2.082
NOX:	$3.418
SOX:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions:	(MW)
1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Coal Steam, 400 MW with FGD

Costs in	1990	dollars
Capital Cost (5) =	$2,082.42	/KW
Fixed O&M Cost (5) =	$35.06	/KW/year
Variable O&M Cost (5) =	$7.38	/MWH
Fuel Cost (6) =	$2.02	/MMBTU
Heat Rate (7) =	9611	BTU/KWH

Cost Escalation Rates (2)	(for 1990)
Capital	6.1%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	5.7%
Air Emissions	5.2%

Air Emission Coefficients (8)	(lbs/MMBTU in)
CO2:	200
CH4:	0.0015
CO:	0.0240
N2O:	0.0325
NOX:	0.2100
SOX:	0.4000
TSP:	0.0300
VOCs:	0.0040

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9) Year	
1	18.57%
2	18.57%
3	18.57%
4	18.57%
5	18.57%
6	18.57%
7	18.57%
8	18.57%
9	18.57%
10	18.57%
11	18.57%
12	18.57%
13	18.57%
14	18.57%
15	18.57%
16	18.57%
17	18.57%

NOTES: (1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.

(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force, Dec 1989, based on p. 16, see Table 5 for calculation of average..

(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.

(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

(5) See note 2, p. 35.

(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39.

(7) See note 2, p. 46, heat rate for net plant heat rate at 80% load.

(8) See note 3 in Table 7.

(9) Levelized charge rate for 20 years. From Table 5.

(10) Plant type used to determine unit costs only.

Table 9 (continued)
Rate Impacts of Coal Plant Purchased Under Contract

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate (cents/KWH)	Annual Rate Inc
1990	110000	$9,600	$0	$0	$0	$0	$0	$9,600	8.73	
1991	112233	$10,301	$205	$19	$26	$67	$317	$10,618	9.46	8.41%
1992	114511	$11,054	$423	$38	$54	$139	$654	$11,708	10.22	8.07%
1993	116836	$11,861	$654	$59	$86	$214	$1,014	$12,875	11.02	7.78%
1994	119208	$12,728	$899	$81	$122	$293	$1,396	$14,124	11.85	7.52%
1995	121628	$13,658	$1,160	$105	$162	$378	$1,804	$15,461	12.71	7.29%
1996	124097	$14,655	$1,436	$129	$206	$466	$2,238	$16,893	13.61	7.09%
1997	126616	$15,726	$1,729	$156	$254	$560	$2,700	$18,426	14.55	6.90%
1998	129186	$16,875	$2,040	$184	$308	$659	$3,191	$20,067	15.53	6.74%
1999	131809	$18,108	$2,371	$213	$367	$764	$3,715	$21,823	16.56	6.59%
2000	134484	$19,431	$2,721	$244	$432	$875	$4,273	$23,704	17.63	6.46%
2001	137214	$20,850	$3,093	$278	$504	$992	$4,866	$25,717	18.74	6.33%
2002	140000	$22,374	$3,488	$313	$582	$1,115	$5,498	$27,872	19.91	6.22%
2003	142842	$24,008	$3,907	$350	$669	$1,246	$6,171	$30,180	21.13	6.12%
2004	145741	$25,762	$4,351	$389	$763	$1,384	$6,888	$32,650	22.40	6.03%
2005	148700	$27,644	$4,823	$431	$866	$1,530	$7,650	$35,295	23.74	5.95%
2006	151719	$29,664	$5,324	$475	$979	$1,684	$8,462	$38,127	25.13	5.87%

NOTES: (1) All costs in nominal dollars for that year.

Costs of Air Emissions

Year	CO2 (cnt/KWH)	CH4 (cnt/KWH)	CO (cnt/KWH)	N2O (cnt/KWH)	NOX (cnt/KWH)	SOX (cnt/KWH)	TSP (cnt/KWH)	VOCs (cnt/KWH)	TOTAL (cnt/KWH)
1990	2.22	0.00	0.01	0.07	0.69	0.30	0.06	0.01	3.36
1991	2.34	0.00	0.01	0.07	0.73	0.32	0.06	0.01	3.54
1992	2.46	0.00	0.01	0.07	0.76	0.34	0.07	0.01	3.72
1993	2.59	0.00	0.01	0.08	0.80	0.35	0.07	0.01	3.91
1994	2.72	0.00	0.01	0.08	0.84	0.37	0.07	0.01	4.12
1995	2.86	0.00	0.01	0.08	0.89	0.39	0.08	0.01	4.33
1996	3.01	0.00	0.01	0.09	0.93	0.41	0.08	0.01	4.55
1997	3.16	0.00	0.01	0.09	0.98	0.43	0.09	0.02	4.79
1998	3.33	0.00	0.02	0.10	1.03	0.45	0.09	0.02	5.04
1999	3.50	0.00	0.02	0.10	1.09	0.48	0.10	0.02	5.30
2000	3.68	0.00	0.02	0.11	1.14	0.50	0.10	0.02	5.57
2001	3.87	0.00	0.02	0.11	1.20	0.53	0.11	0.02	5.86
2002	4.07	0.00	0.02	0.12	1.26	0.56	0.11	0.02	6.16
2003	4.28	0.00	0.02	0.13	1.33	0.58	0.12	0.02	6.48
2004	4.50	0.00	0.02	0.13	1.40	0.61	0.12	0.02	6.81
2005	4.74	0.00	0.02	0.14	1.47	0.65	0.13	0.02	7.17
2006	4.98	0.00	0.02	0.15	1.55	0.68	0.14	0.02	7.54

Table 10
Air Emission Impacts of All Coal Expansion

Quantity from New Generation

Year	CO2 (tons)	CH4 (tons)	CO (tons)	N2O (tons)	NOX (tons)	SOX (tons)	TSP (tons)	VOCs (tons)
1990	0	0	0	0	0	0	0	0
1991	3157214	24	379	513	3315	6314	474	63
1992	6314427	47	758	1026	6630	12629	947	126
1993	9471641	71	1137	1539	9945	18943	1421	189
1994	12628854	95	1515	2052	13260	25258	1894	253
1995	15786068	118	1894	2565	16575	31572	2368	316
1996	18943281	142	2273	3078	19890	37887	2841	379
1997	22100495	166	2652	3591	23206	44201	3315	442
1998	25257708	189	3031	4104	26521	50515	3789	505
1999	28414922	213	3410	4617	29836	56830	4262	568
2000	31572135	237	3789	5130	33151	63144	4736	631
2001	34729349	260	4168	5644	36466	69459	5209	695
2002	37886562	284	4546	6157	39781	75773	5683	758
2003	41043776	308	4925	6670	43096	82088	6157	821
2004	44200989	332	5304	7183	46411	88402	6630	884
2005	47358203	355	5683	7696	49726	94716	7104	947
2006	50515416	379	6062	8209	53041	101031	7577	1010

Value from New Generation

Year	CO2 (1000$)	CH4 (1000$)	CO (1000$)	N2O (1000$)	NOX (1000$)	SOX (1000$)	TSP (1000$)	VOCs (1000$)	Total Value of Emissions (1000$)
1990	$0	$0	$0	$0	$0	$0	$0	$0	$0
1991	$76,828	$6	$360	$2,247	$23,834	$10,476	$2,095	$370	$116,217
1992	$161,600	$12	$758	$4,727	$50,133	$22,036	$4,407	$779	$244,453
1993	$254,935	$19	$1,196	$7,457	$79,088	$34,764	$6,953	$1,228	$385,639
1994	$357,489	$27	$1,677	$10,457	$110,903	$48,749	$9,750	$1,722	$540,773
1995	$469,968	$35	$2,205	$13,747	$145,797	$64,087	$12,817	$2,264	$710,920
1996	$593,123	$44	$2,782	$17,349	$184,003	$80,880	$16,176	$2,858	$897,216
1997	$727,758	$55	$3,414	$21,287	$225,770	$99,240	$19,848	$3,506	$1,100,878
1998	$874,730	$66	$4,103	$25,586	$271,365	$119,281	$23,856	$4,215	$1,323,203
1999	$1,034,956	$78	$4,855	$30,272	$321,072	$141,130	$28,226	$4,987	$1,565,576
2000	$1,209,414	$91	$5,673	$35,375	$375,193	$164,920	$32,984	$5,827	$1,829,477
2001	$1,399,145	$105	$6,563	$40,925	$434,053	$190,793	$38,159	$6,741	$2,116,484
2002	$1,605,265	$120	$7,530	$46,954	$497,997	$218,900	$43,780	$7,734	$2,428,280
2003	$1,828,959	$137	$8,579	$53,497	$567,393	$249,404	$49,881	$8,812	$2,766,663
2004	$2,071,496	$155	$9,717	$60,591	$642,634	$282,477	$56,495	$9,981	$3,133,547
2005	$2,334,224	$175	$10,950	$68,276	$724,140	$318,303	$63,661	$11,247	$3,530,976
2006	$2,618,584	$196	$12,284	$76,594	$812,356	$357,080	$71,416	$12,617	$3,961,127

Table 11
Rate Impacts of Utility-Owned Gas Combined Cycle Plant with Traditional Ratemaking

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4)	(1990$/lb)
CO2:	$0.012
CH4:	$0.116
CO:	$0.452
N2O:	$2.082
NOX:	$3.418
SOX:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions:	(MW)
1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Gas Combined Cycle 200 MW with SCR

Costs in	1990	dollars
Capital Cost (5) =	$656.47	/KW
Fixed O&M Cost (5) =	$11.70	/KW/year
Variable O&M Cost (5) =	$2.05	/MWH
Variable Fuel Cost (6) =	$2.76	/MMBTU
Fixed Fuel Cost (6) =	$1.33	/MMBTU
Heat Rate (7) =	8302	BTU/KWH

Cost Escalation Rates (2)	(for 1990)
Capital	6.4%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	10.3%
Air Emissions	5.2%

Air Emission Coefficients (8)	(lbs/MMBTU In)
CO2:	122
CH4:	0.0019
CO:	0.0210
N2O:	0.0078
NOX:	0.0360
SOX:	0.0006
TSP:	0.0010
VOCs:	0.0330

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9) Year	
1	21.83%
2	21.30%
3	20.54%
4	19.83%
5	19.14%
6	18.49%
7	17.86%
8	17.26%
9	16.68%
10	16.10%
11	15.53%
12	14.95%
13	14.38%
14	13.80%
15	13.23%
16	12.66%
17	12.08%

NOTES: (1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.

(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force , Dec 1989, based on p. 16, see Table 5 for calculation of average..

(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.

(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

(5) See note 2, p. 35.

(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39. Fixed cost does not escalate with time and is based on 75% load.

(7) See note 2, p. 46, heat rate for net plant heat rate at 75% load.

(8) See note 2 in Table 7.

(9) See note 2, p. 32.

(10) Plant type used to determine unit costs only.

Table 11 (continued)
Rate Impacts of Utility-Owned Gas Combined Cycle Plant with Traditional Ratemaking

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate (cents/KWH)	Annual Rate Inc
1990	110000	$9,600	$0	$0	$0	$0	$0	$9,600	8.73	
1991	112233	$10,301	$76	$6	$7	$83	$173	$10,474	9.33	6.93%
1992	114511	$11,054	$155	$13	$15	$175	$358	$11,411	9.97	6.78%
1993	116836	$11,861	$237	$20	$23	$276	$555	$12,416	10.63	6.64%
1994	119208	$12,728	$321	$27	$31	$387	$767	$13,495	11.32	6.52%
1995	121628	$13,658	$409	$35	$40	$510	$994	$14,651	12.05	6.41%
1996	124097	$14,655	$499	$43	$50	$646	$1,238	$15,893	12.81	6.32%
1997	126616	$15,726	$593	$52	$60	$795	$1,500	$17,226	13.61	6.23%
1998	129186	$16,875	$691	$61	$71	$960	$1,783	$18,658	14.44	6.16%
1999	131809	$18,108	$793	$71	$82	$1,142	$2,088	$20,196	15.32	6.09%
2000	134484	$19,431	$900	$82	$94	$1,342	$2,418	$21,849	16.25	6.03%
2001	137214	$20,850	$1,012	$93	$107	$1,563	$2,774	$23,625	17.22	5.98%
2002	140000	$22,374	$1,128	$104	$120	$1,807	$3,160	$25,534	18.24	5.93%
2003	142842	$24,008	$1,250	$117	$135	$2,076	$3,578	$27,586	19.31	5.89%
2004	145741	$25,762	$1,378	$130	$150	$2,373	$4,030	$29,793	20.44	5.85%
2005	148700	$27,644	$1,512	$144	$166	$2,700	$4,521	$32,166	21.63	5.82%
2006	151719	$29,664	$1,652	$159	$183	$3,061	$5,054	$34,719	22.88	5.79%

NOTES: (1) All costs in nominal dollars for that year.

Table 12
Rate Impact of Gas Combined Cycle Plant
Purchased Under Contract

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4)	(1990$/lb)
CO_2:	$0.012
CH_4:	$0.116
CO:	$0.452
N_2O:	$2.082
NO_X:	$3.418
SO_X:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions:	(MW)
1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Gas Combined Cycle 200 MW with SCR

Costs in	1990	dollars
Capital Cost (5) =	$656.47	/KW
Fixed O&M Cost (5) =	$11.70	/KW/year
Variable O&M Cost (5) =	$2.05	/MWH
Variable Fuel Cost (6) =	$2.76	/MMBTU
Fixed Fuel Cost (6) =	$1.33	/MMBTU
Heat Rate (7) =	8302	BTU/KWH

Cost Escalation Rates (2)	(for 1990)
Capital	6.4%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	10.3%
Air Emissions	5.2%

Air Emission Coefficients (8)	(lbs/MMBTU In)
CO_2:	122
CH_4:	0.0019
CO:	0.0210
N_2O:	0.0078
NO_X:	0.0360
SO_X:	0.0006
TSP:	0.0010
VOCs:	0.0330

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9)

Year	
1	18.57%
2	18.57%
3	18.57%
4	18.57%
5	18.57%
6	18.57%
7	18.57%
8	18.57%
9	18.57%
10	18.57%
11	18.57%
12	18.57%
13	18.57%
14	18.57%
15	18.57%
16	18.57%
17	18.57%

NOTES:

(1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.

(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force, Dec 1989, based on p. 16, see Table 5 for calculation of average..

(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.

(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

(5) See note 2, p. 35.

(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39. Fixed cost does not escalate with time and is based on 75% load.

(7) See note 2, p. 46, heat rate for net plant heat rate at 75% load.

(8) See note 2 in Table 7.

(9) See note 2, p. 32.

(10) Plant type used to determine unit costs only.

Table 12 (continued)
Rate Impact of Gas Combined Cycle Plant
Purchased Under Contract

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate (cents/KWH)	Annual Rate Inc
1990	110000	$9,600	$0	$0	$0	$0	$0	$9,600	8.73	
1991	112233	$10,301	$65	$6	$7	$83	$161	$10,462	9.32	6.82%
1992	114511	$11,054	$134	$13	$15	$175	$336	$11,390	9.95	6.70%
1993	116836	$11,861	$207	$20	$24	$276	$527	$12,388	10.60	6.60%
1994	119208	$12,728	$285	$27	$34	$387	$733	$13,461	11.29	6.50%
1995	121628	$13,658	$368	$35	$45	$510	$958	$14,616	12.02	6.42%
1996	124097	$14,655	$456	$43	$57	$646	$1,202	$15,858	12.78	6.34%
1997	126616	$15,726	$550	$52	$71	$795	$1,468	$17,194	13.58	6.27%
1998	129186	$16,875	$650	$61	$86	$960	$1,757	$18,632	14.42	6.21%
1999	131809	$18,108	$756	$71	$102	$1,142	$2,071	$20,179	15.31	6.15%
2000	134484	$19,431	$869	$82	$120	$1,342	$2,413	$21,844	16.24	6.10%
2001	137214	$20,850	$989	$93	$140	$1,563	$2,786	$23,636	17.23	6.05%
2002	140000	$22,374	$1,117	$104	$162	$1,807	$3,191	$25,565	18.26	6.01%
2003	142842	$24,008	$1,253	$117	$186	$2,076	$3,632	$27,640	19.35	5.97%
2004	145741	$25,762	$1,398	$130	$213	$2,373	$4,113	$29,875	20.50	5.93%
2005	148700	$27,644	$1,551	$144	$241	$2,700	$4,636	$32,281	21.71	5.90%
2006	151719	$29,664	$1,715	$159	$273	$3,061	$5,207	$34,871	22.98	5.87%

NOTES: (1) All costs in nominal dollars for that year.

Costs of Air Emissions

Year	CO2 (cnt/KWH)	CH4 (cnt/KWH)	CO (cnt/KWH)	N2O (cnt/KWH)	NOX (cnt/KWH)	SOX (cnt/KWH)	TSP (cnt/KWH)	VOCs (cnt/KWH)	TOTAL (cnt/KWH)
1990	1.17	0.00	0.01	0.01	0.10	0.00	0.00	0.08	1.37
1991	1.23	0.00	0.01	0.01	0.11	0.00	0.00	0.08	1.44
1992	1.30	0.00	0.01	0.01	0.11	0.00	0.00	0.08	1.52
1993	1.36	0.00	0.01	0.02	0.12	0.00	0.00	0.09	1.60
1994	1.43	0.00	0.01	0.02	0.12	0.00	0.00	0.09	1.68
1995	1.51	0.00	0.01	0.02	0.13	0.00	0.00	0.10	1.77
1996	1.59	0.00	0.01	0.02	0.14	0.00	0.00	0.10	1.86
1997	1.67	0.00	0.01	0.02	0.15	0.00	0.00	0.11	1.96
1998	1.75	0.00	0.01	0.02	0.15	0.00	0.00	0.11	2.06
1999	1.84	0.00	0.01	0.02	0.16	0.00	0.00	0.12	2.16
2000	1.94	0.00	0.01	0.02	0.17	0.00	0.00	0.13	2.27
2001	2.04	0.00	0.01	0.02	0.18	0.00	0.00	0.13	2.39
2002	2.15	0.00	0.01	0.02	0.19	0.00	0.00	0.14	2.52
2003	2.26	0.00	0.02	0.03	0.20	0.00	0.00	0.15	2.65
2004	2.37	0.00	0.02	0.03	0.21	0.00	0.00	0.15	2.78
2005	2.50	0.00	0.02	0.03	0.22	0.00	0.00	0.16	2.93
2006	2.63	0.00	0.02	0.03	0.23	0.00	0.00	0.17	3.08

Table 13
Air Emission Impacts of All Gas Combined Cycle Expansion

Quantity from New Generation

Year	CO2 (tons)	CH4 (tons)	CO (tons)	N2O (tons)	NOX (tons)	SOX (tons)	TSP (tons)	VOCs (tons)
1990	0	0	0	0	0	0	0	0
1991	1663596	26	286	106	491	8	14	450
1992	3327193	52	573	213	982	16	27	900
1993	4990789	78	859	319	1473	25	41	1350
1994	6654385	104	1145	425	1964	33	55	1800
1995	8317981	130	1432	532	2454	41	68	2250
1996	9981578	155	1718	638	2945	49	82	2700
1997	11645174	181	2004	745	3436	57	95	3150
1998	13308770	207	2291	851	3927	65	109	3600
1999	14972366	233	2577	957	4418	74	123	4050
2000	16635963	259	2864	1064	4909	82	136	4500
2001	18299559	285	3150	1170	5400	90	150	4950
2002	19963155	311	3436	1276	5891	98	164	5400
2003	21626752	337	3723	1383	6382	106	177	5850
2004	23290348	363	4009	1489	6873	115	191	6300
2005	24953944	389	4295	1595	7363	123	205	6750
2006	26617540	415	4582	1702	7854	131	218	7200

Value from New Generation

Year	CO2 (1000$)	CH4 (1000$)	CO (1000$)	N2O (1000$)	NOX (1000$)	SOX (1000$)	TSP (1000$)	VOCs (1000$)	Total Value of Emissions (1000$)
1990	$0	$0	$0	$0	$0	$0	$0	$0	$0
1991	$40,482	$6	$272	$466	$3,529	$14	$60	$2,638	$47,468
1992	$85,150	$13	$573	$980	$7,424	$29	$127	$5,549	$99,844
1993	$134,330	$21	$904	$1,546	$11,711	$45	$200	$8,753	$157,511
1994	$188,368	$29	$1,267	$2,168	$16,423	$63	$281	$12,275	$220,874
1995	$247,635	$39	$1,666	$2,850	$21,590	$83	$369	$16,137	$290,369
1996	$312,528	$49	$2,103	$3,597	$27,247	$105	$466	$20,366	$366,460
1997	$383,470	$60	$2,580	$4,413	$33,432	$129	$571	$24,988	$449,643
1998	$460,912	$72	$3,101	$5,304	$40,184	$155	$687	$30,035	$540,450
1999	$545,338	$85	$3,669	$6,276	$47,544	$183	$813	$35,536	$639,445
2000	$637,263	$99	$4,288	$7,334	$55,559	$214	$950	$41,527	$747,233
2001	$737,236	$115	$4,961	$8,484	$64,275	$247	$1,099	$48,041	$864,458
2002	$845,845	$132	$5,691	$9,734	$73,744	$284	$1,261	$55,119	$991,808
2003	$963,714	$150	$6,485	$11,091	$84,020	$323	$1,436	$62,799	$1,130,018
2004	$1,091,511	$170	$7,345	$12,561	$95,162	$366	$1,627	$71,127	$1,279,868
2005	$1,229,947	$192	$8,276	$14,154	$107,231	$412	$1,833	$80,148	$1,442,194
2006	$1,379,782	$215	$9,284	$15,879	$120,294	$463	$2,056	$89,912	$1,617,885

Table 14
Rate Impact of Utility-Owned "Clean" Plant

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4)	(1990$/lb)
CO2:	$0.012
CH4:	$0.116
CO:	$0.452
N2O:	$2.082
NOX:	$3.418
SOX:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions:	(MW)
1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Clean Plant with direct costs = 200MW Gas CC direct costs + emissions value

Costs in	1990	dollars
Capital Cost (5) =	$656.47	/KW
Fixed O&M Cost (5) =	$11.70	/KW/year
Variable O&M Cost (5) =	$2.05	/MWH
Variable Fuel Cost (6) =	$2.76	/MMBTU
Fixed Fuel Cost (6) =	$1.33	/MMBTU
Heat Rate (7) =	8302	BTU/KWH

Cost Escalation Rates (2)	(for 1990)
Capital	6.4%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	10.3%
Air Emissions	5.2%

Air Emission Coefficients (8)	(lbs/MMBTU in)
CO2:	0.0000
CH4:	0.0000
CO:	0.0000
N2O:	0.0000
NOX:	0.0000
SOX:	0.0000
TSP:	0.0000
VOCs:	0.0000

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9)

Year	
1	21.83%
2	21.30%
3	20.54%
4	19.83%
5	19.14%
6	18.49%
7	17.86%
8	17.26%
9	16.68%
10	16.10%
11	15.53%
12	14.95%
13	14.38%
14	13.80%
15	13.23%
16	12.66%
17	12.08%

NOTES:

(1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.

(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force , Dec 1989, based on p. 16, see Table 5 for calculation of average..

(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.

(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

(5) See note 2, p. 35.

(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39. Fixed cost does not escalate with time and is based on 75% load.

(7) See note 2, p. 46, heat rate for net plant heat rate at 75% load.

(8) "Clean" plants by definition have zero emissions.

(9) See note 2, p. 32.

(10) Plant type used to determine unit costs only.

Table 14 (continued)
Rate Impact of Utility-Owned "Clean" Plant

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Other (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate cents/KWH
1990	110000	$9,600	$0	$0	$0	$0	$0	$0	$9,600	8.73
1991	112233	$10,301	$76	$6	$7	$47	$83	$220	$10,521	9.37
1992	114511	$11,054	$155	$13	$15	$100	$175	$458	$11,512	10.05
1993	116836	$11,861	$237	$20	$24	$158	$276	$714	$12,575	10.76
1994	119208	$12,728	$321	$27	$34	$221	$387	$990	$13,718	11.51
1995	121628	$13,658	$409	$35	$45	$290	$510	$1,289	$14,947	12.29
1996	124097	$14,655	$499	$43	$57	$366	$646	$1,612	$16,267	13.11
1997	126616	$15,726	$593	$52	$71	$450	$795	$1,961	$17,687	13.97
1998	129186	$16,875	$691	$61	$86	$540	$960	$2,339	$19,214	14.87
1999	131809	$18,108	$793	$71	$102	$639	$1,142	$2,748	$20,856	15.82
2000	134484	$19,431	$900	$82	$120	$747	$1,342	$3,191	$22,622	16.82
2001	137214	$20,850	$1,012	$93	$140	$864	$1,563	$3,672	$24,523	17.87
2002	140000	$22,374	$1,128	$104	$162	$992	$1,807	$4,194	$26,567	18.98
2003	142842	$24,008	$1,250	$117	$186	$1,130	$2,076	$4,759	$28,768	20.14
2004	145741	$25,762	$1,378	$130	$213	$1,280	$2,373	$5,373	$31,135	21.36
2005	148700	$27,644	$1,512	$144	$241	$1,442	$2,700	$6,039	$33,683	22.65
2006	151719	$29,664	$1,652	$159	$273	$1,618	$3,061	$6,762	$36,426	24.01

NOTES: (1) All costs in nominal dollars for that year.

Table 15
Rate Impact of "Clean" Plant Purchased Under Contract

General Input Assumptions

Base Year:	1990	
Current Avg Price (1):	8.73	(cents/KWH)
Cost Escal. of Existing System (2):	5.2%	
Current Sales (3):	110000	GWH
Annual Sales Growth (3):	2.0%	

Air Emission Values (4)	(1990$/lb)
CO2:	$0.012
CH4:	$0.116
CO:	$0.452
N2O:	$2.082
NOX:	$3.418
SOX:	$0.789
TSP:	$2.103
VOCs:	$2.787

New Capacity Additions:	(MW)
1990	0
1991	500
1992	500
1993	500
1994	500
1995	500
1996	500
1997	500
1998	500
1999	500
2000	500
2001	500
2002	500
2003	500
2004	500
2005	500
2006	500

Resource Specific Input Assumptions

Plant Type (10): Clean Plant with direct costs = 200MW Gas CC direct costs + emissions value

Costs in	1990	dollars
Capital Cost (5) =	$656.47	/KW
Fixed O&M Cost (5) =	$11.70	/KW/year
Variable O&M Cost (5) =	$2.05	/MWH
Variable Fuel Cost (6) =	$2.76	/MMBTU
Fixed Fuel Cost (6) =	$1.33	/MMBTU
Heat Rate (7) =	8302	BTU/KWH

Cost Escalation Rates (2)	(for 1990)
Capital	6.4%
Fixed O&M	6.0%
Variable O&M	6.0%
Fuel	10.3%
Air Emissions	5.2%

Air Emission Coefficients (8)	(lbs/MMBTU in)
CO2:	0.0000
CH4:	0.0000
CO:	0.0000
N2O:	0.0000
NOX:	0.0000
SOX:	0.0000
TSP:	0.0000
VOCs:	0.0000

Capacity Factor for New Resources = 75.0%

Annual Carrying Charge Rates (9)

Year	
1	18.57%
2	18.57%
3	18.57%
4	18.57%
5	18.57%
6	18.57%
7	18.57%
8	18.57%
9	18.57%
10	18.57%
11	18.57%
12	18.57%
13	18.57%
14	18.57%
15	18.57%
16	18.57%
17	18.57%

NOTES:

(1) Source: Electric Sales, Revenue, and Bills, 1988, Energy Information Administration, USDOE, Table 12, p. 20.

(2) Source: Summary of Generation Task Force Long-Range Study Assumptions, by NEPLAN Staff and NEPOOL Generation Task Force , Dec 1989, based on p. 16, see Table 5 for calclation of average..

(3) Source: NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1990-2005, April 1 1990. Based on estimated energy demand for 1990 (112184 GWH) on p. 8.

(4) Source: Massachusetts Department of Public Utilities, Order Docket #89-239.

(5) See note 2, p. 35.

(6) See note 2, dispatch price for firm gas excluding variable O&M cost, p. 39. Fixed cost does not escalate with time and is based on 75% load.

(7) See note 2, p. 46, heat rate for net plant heat rate at 75% load.

(8) "Clean" plants by definition have zero emissions.

(9) Levelized charge rate for 20 years. From Table 5.

(10) Plant type used to determine unit costs only.

Table 15 (continued)
Rate Impact of "Clean" Plant Purchased Under Contract

Calculations (1)

Year	Annual Sales (GWH)	Costs Excluding New Gen. (million$)	Costs of New Generation: Capital (million$)	Fix O&M (million$)	Var O&M (million$)	Other (million$)	Fuel (million$)	Total Cost of New Gen. (million$)	Total Cost of Power (million$)	Avg Rate cents/KWH
1990	110000	$9,600	$0	$0	$0	$0	$0	$0	$9,600	8.73
1991	112233	$10,301	$65	$6	$7	$47	$83	$209	$10,510	9.36
1992	114511	$11,054	$134	$13	$15	$100	$175	$436	$11,490	10.03
1993	116836	$11,861	$207	$20	$24	$158	$276	$684	$12,545	10.74
1994	119208	$12,728	$285	$27	$34	$221	$387	$954	$13,682	11.48
1995	121628	$13,658	$368	$35	$45	$290	$510	$1,248	$14,906	12.26
1996	124097	$14,655	$456	$43	$57	$366	$646	$1,569	$16,224	13.07
1997	126616	$15,726	$550	$52	$71	$450	$795	$1,918	$17,644	13.93
1998	129186	$16,875	$650	$61	$86	$540	$960	$2,297	$19,172	14.84
1999	131809	$18,108	$756	$71	$102	$639	$1,142	$2,711	$20,819	15.79
2000	134484	$19,431	$869	$82	$120	$747	$1,342	$3,161	$22,591	16.80
2001	137214	$20,850	$989	$93	$140	$864	$1,563	$3,650	$24,500	17.86
2002	140000	$22,374	$1,117	$104	$162	$992	$1,807	$4,183	$26,556	18.97
2003	142842	$24,008	$1,253	$117	$186	$1,130	$2,076	$4,762	$28,770	20.14
2004	145741	$25,762	$1,398	$130	$213	$1,280	$2,373	$5,393	$31,155	21.38
2005	148700	$27,644	$1,551	$144	$241	$1,442	$2,700	$6,079	$33,723	22.68
2006	151719	$29,664	$1,715	$159	$273	$1,618	$3,061	$6,825	$36,489	24.05

NOTES: (1) All costs in nominal dollars for that year.